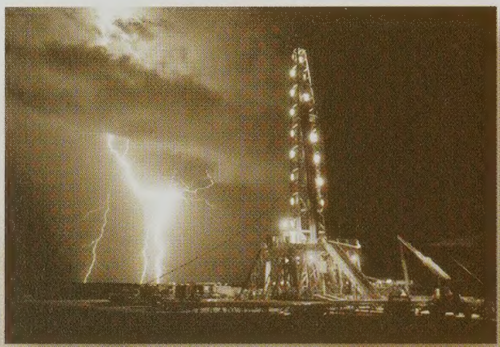
CHIRRIPO RESOURCES INC.

keeping an eye on opportunity

ANNUAL REPORT 2004

CORPORATE PROFILE



Chirripo Resources Inc. is an emerging junior oil and gas company that trades on the TSX Venture Exchange under the symbol "CHO". The Company's headquarters are in Calgary, Alberta.

Chirripo Resources Inc. was incorporated in March 1997 as a junior capital pool company and completed its major transaction in January 1999 by acquiring Chirripo Oil and Gas Ltd.

The Company has grown by using a balanced investment approach of strategic property acquisitions, which complement the Company's operational expertise and low risk exploitation projects that generate near-term cash flow.

As an emerging full-cycle oil and gas company, Chirripo is acquiring larger controlling interests in its focus areas as it strives to lower operating, finding and on-stream costs. With a strong balance sheet and a large undeveloped land base, Chirripo is strategically positioned to participate in high reward exploration projects.

Table of Contents

Annual Meeting

Shareholders are invited to attend the Company's annual meeting, which will be held on Thursday, May 12, 2005 at 3:00 p.m. in the Conference Room, 3rd floor, The Watermark Tower, 530-8th Avenue S.W., Calgary, AB. Shareholders unable to attend the meeting are requested to complete and return the Proxy Form at their earliest convenience to Computershare Trust Company of Canada.

PRESIDENT'S MESSAGE

Fellow shareholders:

The Company changed the direction of its value creation philosophy in 2004. Chirripo's past paradigm concentrated on production and reserves growth through carefully selected property acquisitions that reflected management's entrepreneurial expertise.

In 2004, the acquisition and divestiture environment changed significantly as industry competitors were extremely aggressive at acquiring developed assets. Recognizing the opportunity, the Company sold non-core properties at Bellshill, Joffre and Fireweed for a premium over their proven plus probable values. The resulting proceeds funded 14 percent of the gross capital expenditures for 2004.

For the first time in its corporate history Chirripo relied solely on its drilling and exploitation activities for results, as the Company de-emphasized its acquisition strategy and focused on "growth through the drill bit". The Company's 2004 capital program doubled from the prior year's level to $4.0 million, highlighted by the following accomplishments:

- *80 percent of the 2004 capital program was spent drilling five (1.1 net) oil wells and completing two (1.5 net) gas wells, resulting in 105 boe per day of production;*
- *20 percent of the 2004 capital program was used to acquire 6,440 net undeveloped acres, 12.9 square kilometres of 3-D seismic and 21 kilometres of 2-D seismic; and*
- *increased the Company's reserve base by 15 percent, adding 234,000 barrels of oil equivalent on a proved plus probable basis for a finding and development cost of $14.83 per barrel of oil equivalent.*

In addition, the Company expanded its technical team by contracting an experienced geophysicist and adding an in-house workstation. As a result of the capital and technical commitments Chirripo has made over the past two years, the Company has generated 17 drilling locations in the Company's two core areas, five of which Chirripo will pursue in 2005 pending the success of finding promoted partnerships in which the partner assumes a portion of the drilling costs.

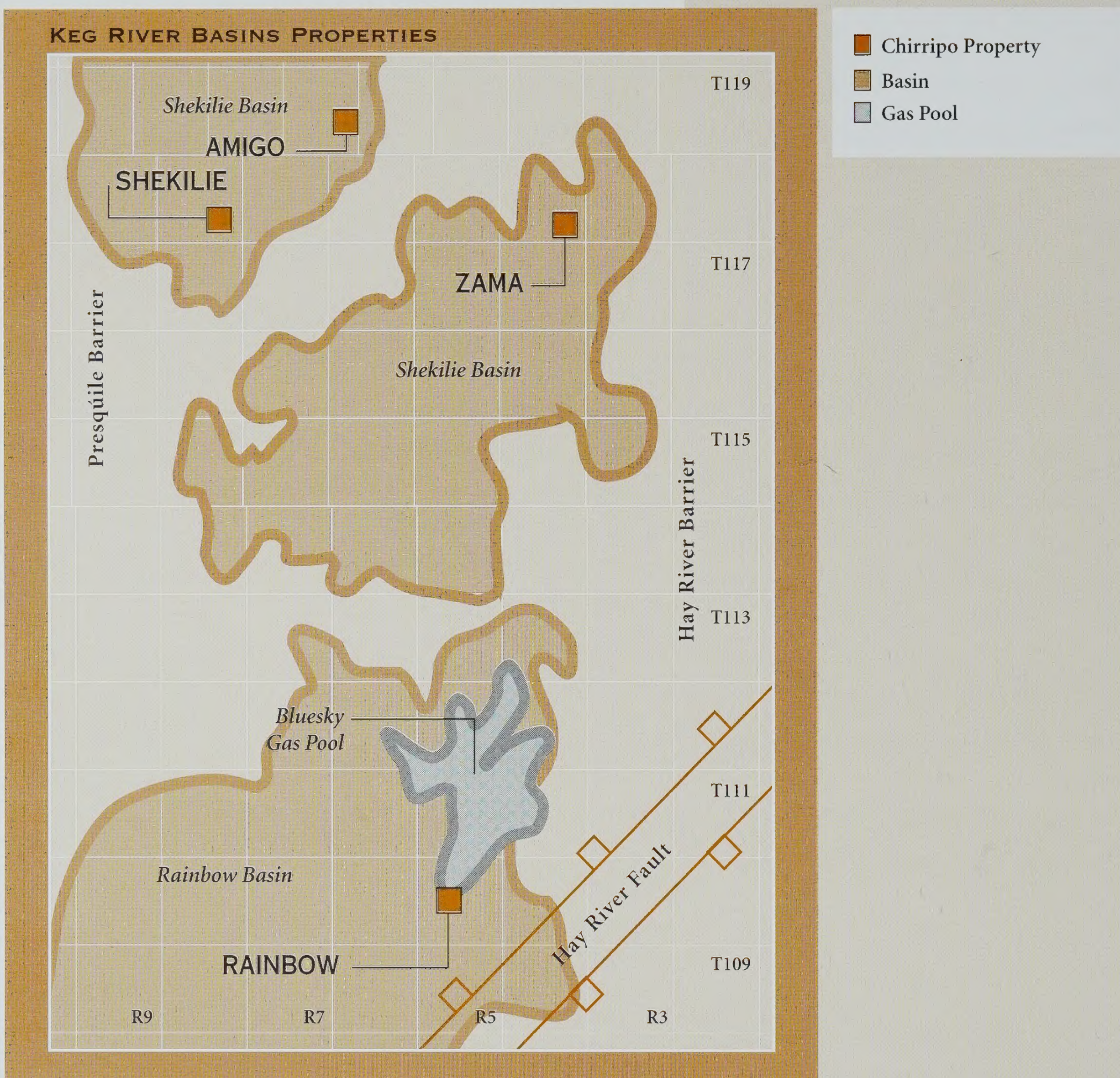
Our purpose remains one of finding quality reserves with dependable production that will generate high netbacks for the Company. The challenge is to execute this goal in an increasingly competitive environment, using resources that are increasingly hard to secure in a timely fashion and accomplishing this objective at attractive returns to the Company's shareholders.

On behalf of the Board of Directors, I would like to express my thanks for the continued support of our investors and the dedication and commitment that our team of professionals has shown towards executing the Company's business objectives.

On behalf of the Board of Directors,

Issa Abu-Zahra
President and Chief Executive Officer
March 30, 2005

REVIEW OF OPERATIONS



KEG RIVER BASINS, ALBERTA

The Company has various working interests in 11.5 sections of land that are situated in the Zama, Shekilie and Rainbow basins. These basins are dominated by pinnacle reef development, composed of stromatopoids and lime sands in the Devonian Keg River and hydrocarbons trapped within the Sulphur Point Formation, as a result of differential compaction over the pre-existing reefs. The Company has acquired 28 square kilometres of 3-D seismic over the last two years and has identified eight prospects in three areas between Townships 110 and 119 and Ranges 4 and 8 W6M.

Chirripo has an average 66 percent working interest in 4 gross (3.0 net) producing oil wells, 1 gross (0.3 net) producing gas well and 1 gross (0.3 net) suspended well in this area. As at December 31, 2004, the daily production to Chirripo from the Keg River Basins was approximately 95 mcf per day of natural gas and 103 bbls per day of oil and NGL. As at December 31, 2004, in this area, the Paddock Reserves Report evaluated Chirripo's proved reserves at 182 mboe and probable reserves at 44 mboe.

REVIEW OF OPERATIONS

AMIGO/ZAMA, ALBERTA

The Company has various working interests in 5.5 sections of land that are situated between Townships 118 and 119 and Ranges 4 and 7. Chirripo purchased 15.5 square kilometres of 3-D seismic in December 2003 to further evaluate its prospect in section 23-118-4 W6M. In February 2004, a well was drilled to its target depth of 1,547 metres, encountering both a Sulphur Point gas zone, which was drill-stem tested at a flow rate of 1.1 mmcf per day and a Keg River oil zone. The oil well was brought on-stream in August, placed on pump in October and produced at a stabilized rate of 63 bbls per day of oil and 10 mcf per day of associated gas in the fourth quarter of 2004. The Company has since acquired additional lands and seismic and intends to drill a similar feature in Township 118 and Range 4 in the winter of 2005/2006.

RAINBOW, ALBERTA

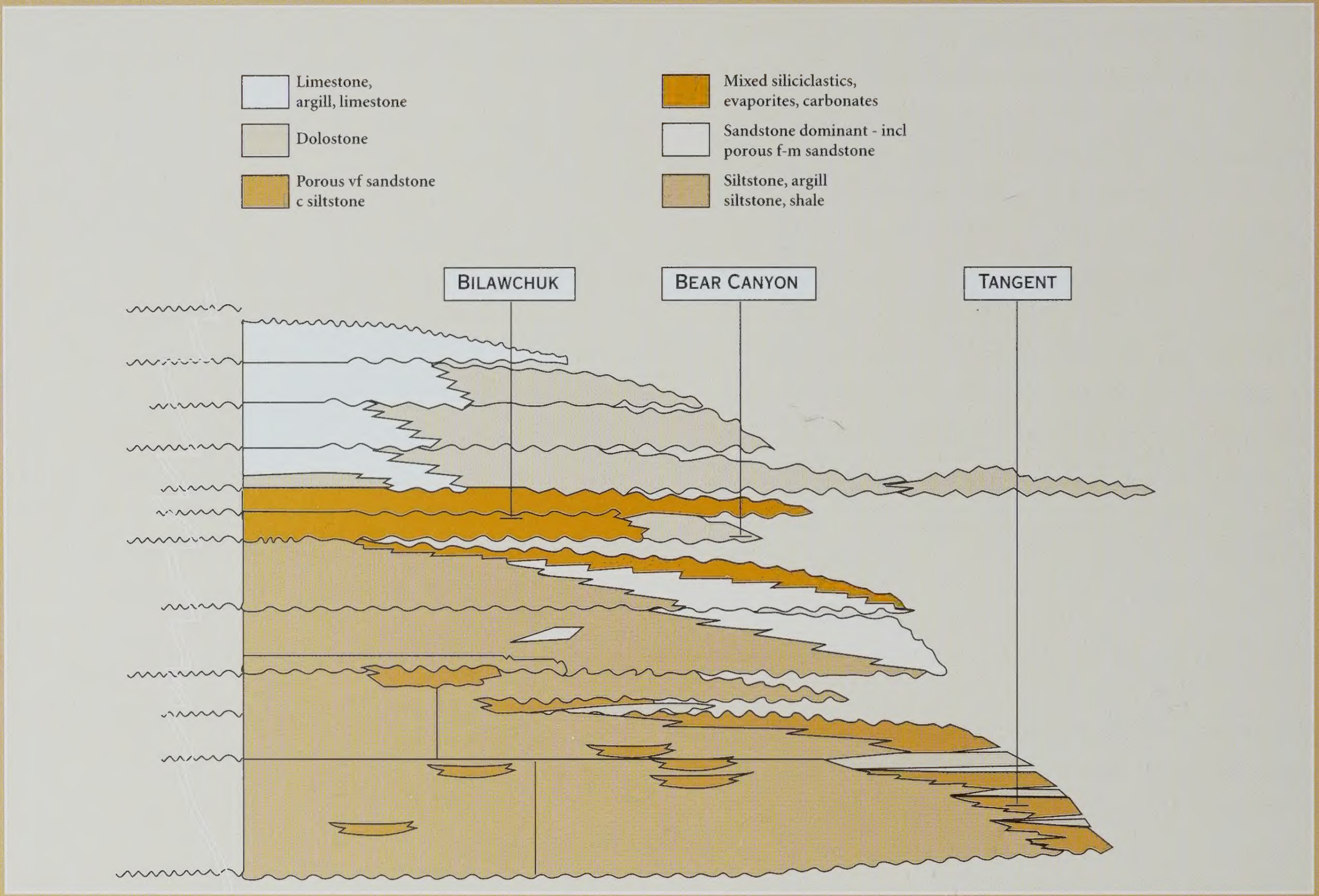
The Company has various working interests in 4.5 sections of land in Township 110 between Ranges 5 and 7 in the Rainbow basin. Chirripo purchased 6.5 square kilometres of 3-D seismic in 2004, covering three sections of 100 percent working-interest lands in Township 110, Range 5 W6M, to further evaluate the potential of two Keg River Reef prospects. Existing well control drilled on the flank of the structure provided a production test of 1,000 mcf per day of gas and 45 bbls per day of 47 degree API oil with 18 percent porosity.

Analogous wells to the north have initially produced in excess of 4,000 mcf per day of gas and 600 bbls per day of oil and have cumulative production of 3.5 bcf of gas and 1.4 million bbls of oil. Chirripo's prospects, although smaller in aerial extent, are estimated at 100,000-300,000 bbls of risked oil and liquids based on closure and evidence of oil from the flank well's production test. Due to the nature of the risk/reward profile of these prospects, the Company has elected to farm out 50 percent of its interest to potential joint-venture partners. Should the initial exploration prospect in section 17-110-5 prove successful, the Company would have two possible follow-up locations. The area has very good well control, with petrophysical logs indicating hydrocarbon potential in the Gething and Banff zones.

SHEKILIE, ALBERTA

The Company has various working interests in 1.5 sections of land situated in Township 118 and Range 8 W6M. Chirripo acquired 5 square kilometres of 3-D seismic in the fourth quarter of 2004 to evaluate two prospects in section 14-118-8 W6M. In February 2004, one well was re-completed in the Sulphur Point at a depth of 1,600 metres. The 3-14 well was both perforated and acidized. The well flowed gas, followed by an influx of water from the lower Keg River formation, due to the failure of poor cement behind the casing. The well was suspended with the intent to follow up and re-drill the well in the winter of 2005/2006. The Company is also evaluating a potential Keg River test in LSD 12 as the original well encountered 35 metres of gas pay, but was unable to be produced due to mechanical problems.

TECTONIC AND STRATIGRAPHIC FRAMEWORK FOR PEACE RIVER ARCH



PEACE RIVER ARCH, ALBERTA

The Peace River Arch area is located in north-central Alberta and includes properties at Gordondale, Rycroft, Elmworth, Bilawchuk, Tangent and Bear Canyon. The Peace River Arch is a natural gas-focused area that offers numerous zones of interest, many of which overlap. Each of the Company's prospects in Tangent and Bear Canyon are targeting at least two productive zones and are scheduled to be drilled this summer should the Company be successful selling a minority interest on a promoted basis.

Chirripo has an average 46 percent working interest in 5 gross (2.0 net) producing oil wells, 10 gross (4.9 net) producing gas wells and 1 gross (0.8 net) suspended well in this area. As at December 31, 2004, the daily production to Chirripo from the Peace River Arch was approximately 527 mcf per day of natural gas and 15 bbls per day of oil and NGL. As at December 31, 2004, in this area, the Paddock Reserve Report evaluated Chirripo's proved reserves at 274 mboe and probable reserves at 47 mboe.

BILAWCHUK, ALBERTA

The Bilawchuk property is located in section 28-80-9 W6M where the Company has one section of land at a 50 percent working interest, located near the Bonanza field. The well was dually completed in the Charlie Lake and Baldonnel formations in December 2004 with equipping and tie-in work expected to be completed before break-up in late March. From extended drill stem tests, the Company anticipates the well will initially produce net 500 mcf per day of gas with associated gas liquids of 8 bbls per day.

TANGENT, ALBERTA

Chirripo has 5.5 sections of undeveloped land with a 100 percent working interest in the Tangent area, which is characterized by multi-zone potential, year-round access and excess capacity at nearby processing infrastructure. The Company acquired 35 kilometres of 2-D seismic over the past two years, to further evaluate the hydrothermal dolomitization along the Normandville/Tangent Fault within the Wabamun Formation and to a lesser extent, the channel sands prevalent in the Montney Formation.

The Company has identified two prospects and plans to drill a Montney opportunity with partners during the summer of 2005. The Montney prospect is a Mississippian high, over which the sands drape with improved porosities. The drilling project will also evaluate potential hydrocarbon-bearing zones in the Belloy, Cadomin and Bluesky sandstones. Both the Bluesky and Cadomin are widespread, five-metre sand deposits with porosity ranging between 15-20 percent. Analagous wells from the Montney Formation typically produce 500 mcf per day initially and recover 0.75 bcf of gas.

The second prospect is a Wabamun opportunity, located in Township 79 and Range 23 W5M, that will evaluate the presence of hydrothermal dolomites along a seismically-defined fault block. The block is believed to have created a halo of dolomitization, trapping the gas. The well will also test the Wabamun prospect for Debolt gas, as the area has produced reserves in excess of 1.5 bcf per well. Wabamun wells typically produce 100 bbls per day initially and recover 150 mbbls of oil.

BEAR CANYON, ALBERTA

The Company has 6.75 sections of undeveloped 100 percent working-interest lands along the Boundary Lake subcrop north-east edge, located north of the Bonanza pool in north-central Alberta. The Company has interpreted 20 kilometres of 2-D seismic, identifying numerous post-Cretaceous east-west faults. The faults have elevated the Baldonnel prior to the generation and migration of hydrocarbons, likely from the overlying Nordegg, a proven source bed, creating an excellent trap. Chirripo's Baldonnel prospect is low risk due to existing well control, as the Company intends to twin a well in section 16-83-12 W6M that encountered 13 metres of 20 percent porosity sand in the Baldonnel.

Analogous Baldonnel wells in the area have cumulative production of 0.7-2.6 bcf of natural gas. Petrophysical logs indicate that there are two separate intervals in the Gething channel sand at 1,100 metres that are prospective as secondary zones. In addition, the Company has two suspended wells located in Townships 82 and 83, Range 12 W6M that are candidates for uphole re-completions as petrophysical logs indicate that the Gething Formation has hydocarbon potential. Analogous Gething wells in the area have cumulative production of 0.6-1.0 bcf of natural gas.

McLEANS CREEK PROPERTIES

McLEANS CREEK, ALBERTA

Chirripo has five sections of 100 percent working-interest land and operates one well at the McLeans Creek property, located in Township 74 and Range 21 W5M. The well has produced a total of 185,000 barrels of oil from the Gilwood Formation. Most of Chirripo's land is covered by the 12.9 square kilometres of 3-D seismic the Company has acquired over the past two years, which has identified two Gilwood drilling opportunities. Should the two development prospects prove successful, the Company will have six possible follow-up locations.

In this area, the Gilwood sands drape over the pre-Cambrian highs. The sands are composed of clean quartz grains with high permeability and an active water-drive. The area has very good well control, with petrophysical logs indicating hydrocarbon potential in the Gething and Bluesky zones. Analogous Gilwood wells in the area have cumulative production of 60-370 mbbls of oil.

The December 31, 2004 Paddock Lindstrom & Associates reserve report (Paddock Report) was prepared utilizing the methodology and definitions set out under National Instrument 51-101 (NI 51-101). The change to proved and probable reserve definitions implemented by NI 51-101 as of December 31, 2003 make it difficult to compare reserve quantities and value to prior years. The resulting values of total proved plus 50 percent risked probable (established) reserves determined in 2002 have been added to the total proved plus probable reserves calculated under NI 51-101 in the Finding, Development and Acquisition Costs section found on page 10. The reserve data provided in this annual report represents only a portion of the disclosure required under NI 51-101. Additional disclosure is available in the Company's NI 51-101 report filed with the Alberta Securities Commission and accessible on SEDAR.

RESERVES – FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT OIL		NATURAL GAS LIQUIDS		NATURAL GAS	
	GROSS (MBBLS)	NET (MBBLS)	GROSS (MBBLS)	NET (MBBLS)	GROSS (MMCF)	NET (MMCF)
Proved						
Developed producing	153	142	5	6	966	933
Developed non-producing	3	2	1	0	1,134	906
Total proved	156	144	6	6	2,100	1,839
Probable	72	69	4	3	1,120	985
Total proved plus probable	228	213	10	9	3,220	2,824

Determined by Paddock Lindstrom & Associates Ltd., independent consultants as at December 31, 2004.
Gross reserves include only working interest reserves. Under NI 51-101 royalty interest reserves owned by the Company are excluded from gross reserves.
Net reserves are the Company's share of all reserves including royalty interest reserves after deduction for Crown, freehold and other royalties.

NET PRESENT VALUE – FORECAST PRICES AND COSTS

RESERVES CATEGORY ($ thousands)	NPV (0%)	NPV (5%)	NPV (10%)	NPV (15%)	NPV (20%)
Proved					
Developed producing	6,906	6,101	5,505	5,043	4,671
Developed non-producing	3,541	2,966	2,535	2,203	1,940
Total proved	10,447	9,066	8,040	7,246	6,611
Probable	4,845	3,589	2,792	2,251	1,863
Total proved plus probable	15,292	12,655	10,832	9,496	8,475

Determined by Paddock Lindstrom & Associates Ltd., independent consultant as at December 31, 2004.
Discounted data represents the present value of estimated future cash flow before income taxes including ARTC.
As required by NI 51-101, well abandonment costs of $0.3 million are included in the net present value calculation.

Forecast Prices

	WTI @ CUSHING	EDMONTON REFERENCE	HENRY HUB	AECO "C"	ALBERTA SPOT
	US$/BBL	CDN$/BBL	US$/MMBTU	CDN$/MMBTU	CDN$/MMBTU
2005	42.00	50.22	6.30	6.78	6.61
2006	40.00	47.76	6.10	6.52	6.34
2007	37.50	44.69	5.90	6.26	6.07
2008	35.00	41.62	5.70	6.00	5.81
2009	33.00	39.16	5.50	5.73	5.54
2010	33.50	39.75	5.61	5.85	5.65
2011	34.00	40.34	5.72	5.96	5.77
2012	34.50	40.92	5.84	6.08	5.88
2013	35.00	41.51	5.95	6.21	6.00
2014	35.50	42.10	6.07	6.33	6.12
2015	36.00	42.68	6.19	6.46	6.24
2016	36.50	43.27	6.32	6.59	6.37
2017	37.00	43.85	6.44	6.72	6.49
2018	37.50	44.44	6.57	6.85	6.62
2019	38.00	45.02	6.70	6.99	6.76

All costs are escalated at 2 percent per year from 2005. All prices are escalated at 2 percent per year after 2019.
A Cdn/U.S. exchange rate of $0.82 was assumed constant for all years presented in this table.

NET PRESENT VALUE – CONSTANT PRICES AND COSTS

RESERVES CATEGORY ($ thousands)	NPV (0%)	NPV (5%)	NPV (10%)	NPV (15%)	NPV (20%)
Proved					
Developed producing	8,241	7,099	6,278	5,658	5,171
Developed non-producing	4,428	3,655	3,086	2,653	2,316
Total proved	12,669	10,754	9,364	8,311	7,487
Probable	6,411	4,665	3,581	2,856	2,343
Total proved plus probable	19,080	15,419	12,945	11,167	9,830

Determined by Paddock Lindstrom & Associates Ltd., independent consultants, as at December 31, 2004.
Discounted data represents the present value of estimated future cash flow before income taxes including ARTC.
As required by NI 51-101, undiscounted well abandonment costs of $0.3 million are included in the net present value calculation.
The constant case assumes prices of Cdn$48.07/bbl for Edmonton reference price for light sweet oil and Cdn$6.88/mcf for AECO "C" for gas.

GROSS RESERVES RECONCILIATION

	PROVED			PROVED + PROBABLE		
	CRUDE OIL & NGL (MSTB)	NATURAL GAS (MMCF)	TOTAL (MBOE)	CRUDE OIL & NGL (MMCF)	NATURAL GAS (MSTB)	TOTAL (MBOE)
December 31, 2003	85	2,221	455	112	3,379	675
Technical revisions	17	3	18	11	(110)	(7)
Discoveries	96	370	158	150	505	234
Dispositions	–	(226)	(38)	–	(286)	(47)
Production	(36)	(268)	(81)	(36)	(268)	(81)
December 31, 2004	162	2,100	512	237	3,220	774

Determined by Paddock Lindstrom & Associates Ltd., independent consultants, as at December 31, 2004.
Gross reserves are based on forecast price and cost assumptions.
Gross reserves include only working interest reserves. Under NI 51-101 royalty interest reserves owned by the Company are excluded from gross reserves.

NET ASSET VALUE

The following net asset value calculation, effective December 31, 2004, is based on reserve values from the Paddock Report and include an internally-generated estimate by management for undeveloped land of $110/acre. The fully diluted calculation includes proceeds from 1,100,500 options and warrants exercisable at an average price of $0.63 per share. The commodity prices that were used in the 2004 forecast reserves evaluation can be found on page 8.

($ thousands, except per share amounts)	10%	15%
Present value of pre-tax reserves including ARTC discounted at [1]	10,832	9,496
Undeveloped land	3,222	3,222
Working capital deficit	(159)	(159)
Bank loans	(1,875)	(1,875)
Net asset value	12,020	10,684
Per share amounts [2]		
Basic	1.09	0.97
Fully diluted	1.05	0.94

(1) Proved plus probable reserves as defined by NI 51-101 based on forecast price and cost assumptions.
(2) Basic shares issued and outstanding at December 31, 2004 – 11,058,768; fully diluted shares issued and outstanding at December 31, 2004 – 12,159,268.
(3) Proved plus probable reserves as defined by NI 51-101 pre-tax including ARTC based on forecast price and cost assumptions.

Using a 10 percent discount factor, the fully diluted net asset value increased 19 percent from $0.88[3] per share at year-end 2003 to $1.05 per share at year-end 2004. The net asset value per share improvement resulted from a 15 percent increase in the Company's proved plus probable reserves, an 8 percent increase in the Company's undeveloped land inventory and a lower working capital deficit position offset by higher debt levels at December 31, 2004.

By comparison, the Company's 2004 fully diluted net asset per share, utilizing constant price and cost assumptions, pre-tax including ARTC, discounted at 10 percent and 15 percent, was $1.22 and $1.07 per share respectively. The commodity prices that were used in the 2004 constant reserves evaluation were Cdn$48.07/bbl for Edmonton reference price – light sweet oil and Cdn$6.88 per mcf for AECO "C" – gas.

Finding, Development and Acquisition (FD&A) Costs

Finding, development and acquisition costs are one measure of a company's ability to add reserves cost-effectively. We calculate the FD&A cost by dividing total capital expenditures incurred during the period by the reserve additions for the same period. The additions included new reserves through drilling, exploitation and acquisitions. A multi-year average FD&A calculation is typically used to judge performance because of the length of time to implement a full-cycle exploration program. Due to reserve definitions implemented by NI 51-101, total proved plus 50 percent risked probable (established) reserves in 2002 have been included with total proved plus probable reserves calculated under 51-101 in 2003 and 2004 for the following three-year period 2002 to 2004.

($ thousands, except where noted)	**2004**	2004-2002
Total capital	**3,471**	6,481
Future development capital	–	477
Total finding, development and acquisition costs	**3,471**	6,958
Reserve additions		
Proved (mboe)	**158**	530
Proved plus probable (mboe)	**234**	764
Costs per boe		
Proved ($/boe)	**21.97**	13.13
Proved plus probable ($/boe)	**14.83**	9.11

Reserve additions based on forecast price and cost assumptions.

Recycle Ratio

The recycle ratio effectively compares the cash generated by each boe produced to the cost of replacing each boe. The ratio is calculated by dividing the Company's average field netback during the period by its FD&A cost for the same period. In 2004, Chirripo achieved a recycle ratio of 1.2 times (2003 – 0.8 times) on a proved basis and 1.8 times (2003 – 2.1 times) on a proved plus probable basis utilizing a 2004 field netback of $27.10 per boe (2003 – $22.03). See detailed field netback calculation on page 14 of the Management's Discussion and Analysis.

Land Holdings

The following table discloses the Company's developed and undeveloped land holdings in acres as well as Chirripo's net working interest at December 31, 2003 and 2004:

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
2003	33,213	6,658	56,593	27,222	89,806	33,880
2004						
Peace River Arch	16,198	5,037	28,214	17,300	44,412	22,337
Keg River Basins	1,920	569	7,200	6,793	9,120	7,362
Central Plains	11,205	553	9,515	3,875	20,720	4,428
Other	4,162	884	13,600	1,320	17,762	2,204
Total	33,485	7,043	58,529	29,288	92,014	36,331

"Gross" means the total number of acres in which the Company has an interest.
"Net" refers to the aggregate of the percentage interests of the Company in the gross acres.

The following Management's Discussion and Analysis (MD&A) of financial condition should be read in conjunction with the Company's audited financial statements and notes for the years ended December 31, 2004 and 2003.

Where amounts are expressed on a barrel of oil equivalent basis (boe), natural gas volumes have been converted to barrels of oil at six thousand cubic feet (mcf) per barrel (bbl). Boe figures may be misleading, particularly if used in isolation. A boe conversion of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Cash flow from operations, as used in the MD&A, is not defined under Generally Accepted Accounting Principles (GAAP). The reconciliation between net income and cash flow from operations can be found in the Selected Annual Information section on page 14. Cash flow from operations per share is calculated using the weighted average shares outstanding, consistent with the calculations of net income per share.

References to oil in this discussion include crude oil and natural gas liquids (NGL). NGL include condensate, butane and propane. This discussion contains certain forward-looking statements that are based on assumptions about future events and are subject to risks and uncertainties that may cause actual results to vary materially from these statements.

CHANGES IN ACCOUNTING POLICIES

ASSET RETIREMENT OBLIGATIONS

In 2004, the Company retroactively adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for asset retirement obligations. These recommendations replaced the former policy on future site restoration, and as a result, have been treated as a change in accounting policy. The new pronouncement requires the Company to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying value of the related long-lived asset. This change in accounting policy is described further in Notes 2 and 6 to the financial statements.

FULL COST ACCOUNTING GUIDELINE

Effective January 1, 2004, the Company adopted AcG-16 "Oil and Gas Accounting – Full Cost". The new guideline issued by the CICA replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry". Under AcG-16, future net revenues for ceiling test purposes are based on proved plus probable reserves and forecast pricing and are discounted. Estimated general and administrative costs and financing charges are no longer contemplated in the ceiling test. This change in accounting policy is described further in Note 2 to the financial statements.

CRITICAL ACCOUNTING ESTIMATES

Full Cost Accounting

The Company follows the full cost method of accounting for its oil and gas activities, whereby all costs related to the acquisition of, exploration for and development of oil and gas properties and related reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenditures, costs of drilling productive and non-productive wells, production equipment, a portion of general and administrative expenditures related to exploration activities and the estimated net present value of related future asset retirement obligations. Proceeds from the disposal of oil and gas properties and production equipment are applied as a reduction of the cost of the remaining assets, except when such a disposal would change the depletion and depreciation rate by more than 20 percent. In that case, a gain or loss on disposal would be recorded.

Capitalized costs of oil and gas properties and production equipment, excluding the cost of unproved properties, are depleted and depreciated using the unit-of-production method based on estimated proved reserves of oil and gas before royalties as determined by an independent reserve engineer. Costs of acquiring and evaluating unproved properties are excluded from depletion costs until proved reserves have been established or impairment occurs.

Oil and Gas Reserves

The Company evaluates its reserves in accordance with National Instrument (NI) 51-101, the new standard of disclosure for oil and gas activities. The oil and gas reserve estimates also incorporate all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's capital expenditure activities.

Impairment of Property and Equipment

The Company applies a ceiling test to capitalized costs on a quarterly basis to ensure that such costs do not exceed the fair value of the properties. The capitalized costs are assessed to be recoverable when the sum of the non-discounted cash flows expected from the production of proved reserves, undeveloped land and future development projects exceeds the carrying amount of the cost centre. When the capitalized costs are not assessed to be recoverable, an impairment loss is recognized. In that case, the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, undeveloped land and future development projects of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of industry guidelines and management's estimate on a well-by-well basis. The liability is subsequently adjusted due to the passage of time and is recognized as an accretion expense in the statement of operations and retained earnings. The liability is further adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. The increase in the carrying value of the capital asset is amortized using the unit-of-production method based on estimated gross proved reserves as determined by independent engineers.

Stock-Based Compensation

Under the Company's stock option plan, options to purchase common shares are granted to directors, officers and employees at current market prices. Options issued by the Company since January 1, 2003 have been recorded utilizing the "fair value method" of accounting for stock-based compensation whereby the value of the option is charged to income, with an offsetting amount recorded to contributed surplus. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model.

CONTRACTUAL OBLIGATIONS

Office Space

The Company has entered into an office rental lease that expires in January 2007. The amount paid under this lease during 2004 was $68,190. The Company's identified contractual obligations as of the date of this report have not changed materially since December 31, 2004.

OUTSTANDING SHARE DATA

From December 31, 2004 to the date of this report, the following options have been exercised: 75,000 common share purchase warrants ($0.85 per share); 65,000 options ($0.11 per share); 35,000 options ($0.25 per share), and 15,000 options ($0.30 per share). As a result, at the date of this report, the Company has 11,248,768 common shares issued and outstanding.

OFF-BALANCE SHEET ARRANGEMENTS

The Company does not have any special purpose entities nor is it a party to any arrangement that would be excluded from the balance sheet.

SELECTED ANNUAL INFORMATION

Operating Highlights

	2004	2003	2002
FIELD NETBACKS – EQUIVALENT UNIT ($/BOE)			
Oil and gas revenue	**43.59**	38.01	28.27
Royalties net of ARTC	**6.80**	6.96	4.80
Operating costs	**9.69**	9.02	9.13
Field netback	**27.10**	22.03	14.34
CASH EXPENSES – EQUIVALENT UNIT ($/BOE)			
General and administrative expenses	**7.26**	5.77	6.82
Financing charges net of other income	**0.95**	0.80	1.48
Current income taxes	**–**	1.16	–
Cash flow from operations	**18.89**	14.30	6.04
NON-CASH EXPENSES – EQUIVALENT UNIT ($/BOE)			
Depletion and depreciation	**10.34**	8.24	7.20
Accretion	**0.52**	0.47	0.40
Stock-based compensation	**0.61**	0.07	–
Future income taxes	**2.37**	0.88	1.11
Net earnings (loss)	**5.05**	4.64	(2.67)

AVERAGE SELLING PRICES			
Natural gas ($/mcf)	**6.48**	6.31	4.20
Oil and NGL ($/bbl)	**49.68**	38.44	35.10
Average ($/boe)	**43.59**	38.01	28.27

AVERAGE DAILY SALES			
Natural gas (mcf/d)	**791**	981	620
Oil and NGL (bbls/d)	**102**	62	45
Average (boe/d)	**234**	226	145

Financial Highlights

($000s, except per share amounts)

Oil and gas revenue	**3,724**	3,134	1,501
Cash flow from operations	**1,613**	1,179	302
Per share – diluted	**0.15**	0.14	0.05
Net earnings (loss)	**431**	383	(142)
Per share – diluted	**0.04**	0.05	(0.02)
Net capital expenditures	**3,471**	2,044	966
Total assets per balance sheet	**8,008**	4,882	3,415
Total liabilities	**4,018**	3,279	2,118

SELECTED QUARTERLY INFORMATION

Operating Highlights

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FIELD NETBACKS – EQUIVALENT UNIT ($/BOE)								
Oil and gas revenue	46.60	44.39	42.91	39.25	35.01	35.16	38.07	44.30
Royalties net of ARTC	4.73	10.20	7.15	4.45	4.31	6.40	7.49	9.92
Operating costs	11.83	9.00	8.74	8.83	7.98	9.46	10.71	7.90
Field netback	30.04	25.19	27.02	25.97	22.72	19.30	19.87	26.48
CASH EXPENSES – EQUIVALENT UNIT ($/BOE)								
General and administrative expenses	8.90	5.27	8.30	6.84	7.11	4.79	5.73	5.35
Financing charges net of other income	1.17	1.06	1.20	0.15	0.48	0.95	0.99	0.79
Current income taxes (recoveries)	–	–	–	–	(4.69)	4.13	4.23	1.13
Cash flow from operations	19.97	18.86	17.43	18.98	19.82	9.43	8.92	19.21
NON-CASH EXPENSES – EQUIVALENT UNIT ($/BOE)								
Depletion and depreciation	13.43	9.77	9.02	8.78	10.64	7.61	7.35	7.21
Accretion	0.50	0.45	0.59	0.59	0.31	0.46	0.47	0.49
Stock-based compensation	0.66	0.56	0.60	0.62	0.26	–	–	–
Future income taxes (recoveries)	2.99	2.63	3.16	0.52	3.84	(2.85)	(1.70)	4.41
Net earnings	2.39	5.45	4.06	8.47	4.77	4.21	2.80	7.10
AVERAGE SELLING PRICES								
Natural gas ($/mcf)	6.81	6.10	6.77	6.25	5.85	5.61	6.38	7.29
Oil and NGL ($/bbl)	52.21	52.37	47.27	42.32	34.81	37.90	37.32	46.47
Average ($/boe)	46.60	44.39	42.91	39.25	35.01	35.16	38.07	44.30
AVERAGE DAILY SALES								
Natural gas (mcf/d)	761	829	800	772	964	891	1,046	1,025
Oil and NGL(bbls/d)	130	135	70	73	71	81	52	45
Average (boe/d)	257	273	203	202	232	229	226	216

Financial Highlights

($000s, except per share amounts)

	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Oil and gas revenue	1,101	1,117	793	713	747	741	783	863
Cash flow from operations	472	474	322	345	423	199	183	374
Per share – diluted	0.04	0.04	0.03	0.04	0.05	0.02	0.02	0.05
Net earnings	65	137	75	154	99	88	58	138
Per share – diluted	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02
Net capital expenditures	838	582	564	1,487	1,008	141	250	645

SALES VOLUMES

	2004	2003	% CHANGE
Natural gas (mcf/d)	**791**	981	(19)
Oil and NGL (bbls/d)	**102**	62	65
Average (boe/d)	**234**	226	4

Production averaged 234 boe per day in 2004, a slight increase of 4 percent from 226 boe per day in 2003. Natural gas sales declined 19 percent, on a year-over-year basis, to 791 mcf per day in 2004. The decrease in gas sales was primarily due to production declines from the Company's wells at Gordondale and Shekilie. Oil and NGL sales increased 65 percent to 102 bbls per day in 2004, from the prior year's 62 bbls per day. All of the production gains were generated from the Amigo area, which came from one reactivated well, a fourth quarter 2003 acquisition and a first quarter 2004 oil discovery that was placed on production August 2004. Included in the Company's oil and liquids average sales for 2004 is 7 (2003 – 7) bbls per day of NGL.

The new production gains from the Amigo and Greencourt property contributed substantially to 2004 fourth-quarter sales, which increased 11 percent to 257 boe per day. The 2004 volume was comprised of 761 mcf per day of gas and 130 bbls per day of oil and NGL. This compares to 232 boe per day for the same three-month period in 2003, which consisted of 964 mcf per day of gas and 71 bbls per day of oil and NGL.

SELLING PRICES

	2004	2003	% CHANGE
Natural gas ($/mcf)	**6.48**	6.31	3
Oil and NGL ($/bbl)	**49.68**	38.44	29
Average ($/boe)	**43.59**	38.01	15

World supply concerns, coupled with political uncertainty in the Middle East, continued to drive 2004 oil prices, which increased the Company's average oil price 29 percent to $50.49 per bbl from $39.12 per bbl in 2003. Chirripo's NGL prices followed suit, increasing 17 percent to $39.17 per bbl in 2004 from $33.47 in 2003. As a result, the Company's average price for oil and NGL rose 29 percent to $49.68 per bbl in 2004 from $38.44 in 2003.

Similarly, the fourth-quarter 2004 oil and NGL price of $52.21 per bb1 was 50 percent higher than the $34.81 per bbl realized for the comparative period in 2003. In 2004, gas prices continued to rise by a modest 3 percent to $6.48 per mcf from the prior year's $6.31 per mcf. Natural gas prices increased 16 percent to $6.81 per mcf in the fourth quarter of 2004, versus $5.85 realized in the same three-month period in 2003.

SALES REVENUE

($000s)	2004	2003	% CHANGE
Natural gas	1,869	2,259	(17)
Oil and NGL	1,855	875	112
Total	3,724	3,134	19

Total revenue increased 19 percent to $3,724,458 in 2004 from $3,133,655 for the comparative period in 2003. Oil and natural gas liquids revenues for 2004 increased 112 percent to $1,855,313 from $874,920 for the same period in 2003, due to a 65 percent increase in sales volumes and a 29 percent increase in prices. Natural gas revenues for 2004 fell 17 percent to $1,869,145 from the prior year's level of $2,258,735 as the decline in average sales volumes in 2004 offset any benefit of the slightly higher sales price.

An 83 percent increase in sales volumes, combined with a 50 percent increase in prices, improved oil and NGL revenues by 174 percent to $624,261 for the fourth quarter of 2004 versus $228,193 generated during the same period in 2003. Stronger prices in the final quarter of 2004 were not enough to offset lower average sales volumes as fourth-quarter 2004 gas revenue decreased to $476,358 from $518,986 realized in the same period of 2003.

ROYALTY EXPENSE

($000s)	2004	2003	% CHANGE
Crown	**599**	559	7
Overriding	**54**	37	46
Alberta Royalty Tax Credit	**(72)**	(22)	227
Total	**581**	574	1

Royalties as a percentage of working interest sales revenue decreased to 16.3 percent in 2004 from 19.2 percent in 2003. The decline in the Company's effective royalty rate is attributable to the Company's new oil production qualifying for Alberta royalty tax relief. On an equivalent unit basis, royalties averaged $6.80 per boe in 2004 compared to $6.96 per boe in 2003. The overall increase in royalty expense was primarily caused by higher total revenues as well as a relative increase in Crown royalty rates due to higher commodity prices.

On an equivalent unit basis, royalties averaged $4.73 per boe in the fourth quarter of 2004 versus $4.31 per boe in the last quarter of 2003. The higher per unit rate is reflective of the 33 percent overall increase in year-over-year fourth-quarter commodity prices.

Operating Expense

Operating expenses increased 11 percent to $827,967 in 2004 from $743,905 in 2003, while per unit operating costs were $9.69 per boe in 2004 versus $9.02 per boe. The increased cost reflects higher production as well as third-party expenses for contract operating, gathering, treating, and compression.

Chirripo's fourth-quarter 2004 unit operating costs jumped to $11.83 per boe from $7.98 per boe realized in the last quarter of 2003. The increase was due in part to a $1.52 per boe effect of under estimating operating expenses to September 30, 2004 and high de-waxing, contract operating costs and downtime associated with the optimization of the Company's new oil well at Amigo.

General and Administrative Expenses

General and administrative expenses for 2004 increased 31 percent to $620,694 from $474,626 incurred in 2003. The higher costs resulted from additional fees associated with the Company's increased compliance responsibilities such as reserve evaluations (National Instrument 51-101), auditing (quarterly reviews) and directors' fees (five independent directors in 2004 versus three in 2003). In addition, geophysical and engineering consulting costs were higher in 2004 to support Chirripo's increased capital expenditure program. Higher salary costs also contributed to the overall increase in general and administrative expenses as staff payroll was increased to more closely reflect market compensation levels. As a result, on a per boe basis, the rate increased 26 percent to $7.26 compared to $5.77 in 2003.

Financing Charges

The 2004 interest expense, which includes bank charges and is net of other income of $81,043, increased 23 percent over 2003's amount of $66,104. The 2004 interest expense resulted from the Company's higher average debt levels incurred in 2004, reflecting management's decision to finance 26 percent of the Company's expanded capital program. Chirripo amended its acquisition facility to include a $600,000 development facility to finance tie-in costs and increased its operating facility from $1.8 million in 2003 to $2.4 million as of May 2004. As a result, the rate increased 19 percent to $0.95 per boe versus $0.80 per boe recorded in 2003.

Depletion and depreciation

Depletion and depreciation charges calculated on a unit-of-production method are based on total proved reserves. In 2004, depletion and depreciation expense increased 30 percent to $883,118 from $679,004 realized in 2003. On a per unit basis, depletion expense increased from $7.40 per boe recorded in 2003 to $9.77 per boe realized in 2004, reflecting the costs of the gathering infrastructure built for the Company's two new operated wells. Included in the Company's 2004 depletion and depreciation expense is $39,600 (2003 – $61,566) or $0.46 per boe (2003 – $0.75 per boe) related to the Company's asset retirement cost and $8,362 (2003 – $7,023) or $0.10 per boe (2003 – $0.09 per boe) related to the Company's furniture and computer equipment.

ACCRETION EXPENSE

Accretion represents the time value of the Company's asset retirement obligation, which will continue to increase with time and increases in Chirripo's asset retirement obligations. Accretion expense for 2004 increased 15 percent to $44,366 from $38,672 in 2003.

INCOME TAXES

The following table describes Chirripo's future tax pools at December 31:

($000s)	2004	2003
Canadian oil and gas property expense	**1,545**	1,604
Canadian development expense	**1,714**	625
Undepreciated capital cost	**1,284**	544
Non-capital losses	**140**	–
Share issuance costs	**110**	–
Total	**4,793**	2,772

The Company's 2004 provision for income taxes reflects the impact of the 70 percent increase in capital expenditures over prior year's levels. The Company does not have to pay income tax in 2004 and has lowered the effective rate on future taxes when these taxes are expected to be paid. The Company's 2004 effective tax rate on future taxes is lower than anticipated due to the future tax benefit of unused share issuance costs of $109,654 and a non-capital loss carryforward of $140,558. At December 31, 2004 Chirripo had cumulative tax pools of $4,792,801 available to reduce future taxable income.

EARNINGS AND CASH FLOW FROM OPERATIONS

The Company's 2004 net earnings climbed 13 percent to $431,254 ($0.04 per share – fully diluted) compared with $382,630 ($0.05 per share – fully diluted) in 2003. A 23 percent improvement in the Company's field netback was the significant factor contributing to the Company's improved earnings in 2004. The Company's improved operating margins, combined with an increased capital expenditure program which shielded earnings from current tax, helped offset the effect of increased general and administrative expenses and higher financing charges. These factors improved cash flow from operations by 37 percent to $1,613,473 in 2004 ($0.15 per share – fully diluted) compared with $1,178,946 for 2003 ($0.14 per share – fully diluted).

Capital Expenditures

($000s)	2004	2003
Land and seismic	**811**	565
Drilling and completions	**2,022**	770
Production equipment	**1,193**	175
Property acquisitions	**–**	562
Office	**3**	13
Total capital expenditures	**4,029**	2,085
Property dispositions	**(558)**	(41)
Net capital expenditures	**3,471**	2,044

Chirripo increased the capital spending program net of dispositions by 70 percent to $3,471,384 in 2004 from $2,043,699 spent in 2003. The Company participated in drilling 5 (1.1 net) oil wells and completing 2 (1.5 net) gas wells; acquired a total of 6,440 net undeveloped acres, 12.9 square kilometres of 3-D and 21 kilometres of 2-D seismic. In addition, the company sold non-core properties at Fireweed, Joffre and Bellshill for proceeds of $557,684. The Oil discovery at Amigo began producing on August 18 at a flush rate of 222 bbls per day of light oil and 95 mcf per day of natural gas. Production averaged 65 boe per day in the third quarter and stabilized at 62 boe per day in the fourth quarter. The Amigo well also encountered natural gas in the Sulphur Point formation, testing 1 mmcf per day. The zone will not be on-stream until 2008.

Liquidity and capital resources

($000s)	2004	2003
Cash flow from operations	**1,613**	1,180
Proceeds from common shares issued	**1,853**	35
Increase (decrease) in bank debt	**900**	(145)
(Increase) decrease in working capital	**(895)**	974
Total	**3,471**	2,044

The Company's 2004 capital expenditure program was funded 21 percent by cash flow from operations (2003 – 51 percent), 53 percent (2003 – 2 percent) from two private placements (2,597,100 common shares), at an average price of $0.77 per common share, less issuance costs of $137,066 (see Note 7 to the financial statements) and the balance from debt. Chirripo's operating demand loan provides for a line of credit of $2.4 million, of which $525,000 remained unused at year end. In addition to the operating line, the Company has an unused acquisition demand loan of $1.5 million, including a $600,000 development facility. At March 30, 2005, Chirripo had 11,248,768 common shares issued and outstanding and 910,500 stock options with a weighted average exercise price of $0.67 per share.

BUSINESS RISKS

The business of exploring for, developing and producing oil and natural gas reserves involves substantial financial, operational and regulatory risks that have the potential to significantly affect Chirripo's results.

Operationally, there is substantial exploration risk related to the human and capital resources allocated to finding oil and natural gas reserves in economic quantities. Selling profitable reserves may be delayed for long periods of time due to processing constraints at third-party plants or lack of transportation capacity through third-party gathering systems. Forecast production from oil and natural gas reservoirs may decline more quickly than anticipated, resulting in lower cash flow and reserve recovery. Chirripo competes directly for petroleum and natural gas leases and field services with entities that have greater technical and financial resources.

Financially, the price Chirripo receives for oil, natural gas and natural gas liquids fluctuates continually and, for the most part, is beyond the Company's control. Chirripo's growth is partially dependent upon external sources of financing which may not be available on acceptable terms.

Chirripo's operations are subject to extensive environmental controls and regulations by various levels of government and there is risk that future changes in government policy could adversely impact Chirripo's profitabilty.

Chirripo mitigates these risks by hiring highly qualified personnel; focusing operational efforts in geographic areas with high-quality reservoirs where the Company has existing knowledge and expertise, and access to third-party facilities; and when appropriate, undertakes a certain portion of its activities jointly with industry partners. Chirripo is currently selling its products through daily spot contracts with 30-day termination notices.

CORPORATE OUTLOOK

During the fourth quarter, the Company successfully retested and completed 1 (0.5 net) gas well in Bilawchuk, which was tied-in by the end of March 2005, with an anticipated initial net production rate of 500 mcf per day. The Company also participated in re-completing 1 (0.5 net) gas well at Amigo in the first quarter of 2005, which Chirripo anticipates will add net flush production of 450 mcf per day when the well is brought on-stream. In addition, Chirripo participated in the reactivation of an oil well in Gordondale, which also qualified for royalty relief status. The Company concluded its 2004 capital program by participating in drilling 3 (0.3 net) wells in December which resulted in 2 (0.1 net) oil wells and 1 (0.2 net) abandoned well; the exploration well in the Sundown area of northeast British Columbia, which targeted both the Caddotte and Notikewin formations, was wet. When combined, these projects are anticipated to add 110 boe per day of net production to Chirripo's second quarter rate for 2005.

The Board of Directors has approved a 2005 capital budget of $3.3 million which will be funded from cash flow and available lines of credit. The Company anticipates drilling 3 (2.0 net) exploration wells and 2 (1.3 net) development wells. Additional funds are available for the acquisition of land, seismic and producing properties should opportunities arise in the Company's two core areas.

Management's Report to the Shareholders

The accompanying financial statements and all operational and financial information in this annual report are the responsibility of management. The financial statements, which include estimates based on management's objective and informed judgements, have been prepared in accordance with Canadian generally accepted accounting principles. Management is satisfied that the financial information throughout this annual report is consistent with the information presented in the financial statements.

Management is also responsible for maintaining a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that the accounting system provides timely, accurate and reliable financial information.

The Audit Committee is composed entirely of Directors who have no direct or indirect relationship with the Company. The external auditors have full and free access to the Audit Committee. The Audit Committee is responsible for overseeing management in the performance of its financial reporting responsibilities and for approving the financial information in the annual report. The Audit Committee fulfils these responsibilities by reviewing the financial information prepared by management and discussing relevant matters with management and the external auditors.

Meyers Norris Penny LLP, an independent firm of Chartered Accountants, is appointed by the Committee to audit the financial statements of the Company for the years ended December 31, 2003 and 2004. The Board of Directors has approved the financial statements of the Company on the recommendation of the Audit Committee.

Issa Abu-Zahra
President and Chief Executive Officer

David Dakers
Corporate Secretary and Chief Financial Officer

Calgary, Alberta
March 30, 2005

We have audited the balance sheets of Chirripo Resources Inc. as at December 31, 2004 and 2003 and the statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Meyers Norris Penny LLP

Chartered Accountants

Calgary, Alberta
March 14, 2005

As at December 31	**2004**	2003 (restated)
ASSETS		
Current		
Cash	**3,393**	15,968
Accounts receivable	**690,916**	234,186
ARTC receivable	**72,455**	22,008
Prepaid expenses and deposits	**32,202**	24,826
	798,966	296,988
Property and equipment *(Note 3)*	**7,208,897**	4,584,883
	8,007,863	4,881,871
LIABILITIES		
Current		
Accounts payable and accruals	**957,845**	1,222,148
Bank loans *(Note 4)*	**1,875,000**	975,000
Income taxes payable *(Note 5)*	**–**	96,000
	2,832,845	2,293,148
Future income taxes *(Note 5)*	**689,784**	536,950
Asset retirement obligations *(Note 6)*	**495,835**	448,948
	4,018,464	3,279,046
SHAREHOLDERS' EQUITY		
Share capital *(Note 7)*	**2,983,762**	1,080,040
Contributed surplus *(Note 8)*	**57,198**	5,600
Retained earnings	**948,439**	517,185
	3,989,399	1,602,825
	8,007,863	4,881,871

Approved on behalf of the Board:

William R. Miller
Director

M. A. Williams

Michael A. Williams
Director

Statements of Operations and Retained Earnings

For the years ended December 31	2004	2003 (restated)
Revenue		
Petroleum and natural gas sales	**3,563,812**	2,983,675
Royalty income	**160,646**	149,980
Royalty expense net of ARTC	**(581,281)**	(574,074)
	3,143,177	2,559,581
Expenses		
Operating	**827,967**	743,905
General and administrative	**620,694**	474,626
Interest and bank charges	**87,538**	73,600
Accretion *(Note 6)*	**44,366**	38,762
Depletion and depreciation	**883,118**	679,004
Stock-based compensation *(Note 8)*	**51,598**	5,600
	2,515,281	2,015,497
Earnings from operations	**627,896**	544,084
Other income	**6,495**	7,496
Earnings before income taxes	**634,391**	551,580
Income taxes *(Note 5)*		
Current	**–**	96,000
Future	**203,137**	72,950
	203,137	168,950
Net earnings	**431,254**	382,630
Retained earnings, beginning of year as previously stated	**600,316**	252,100
Change in accounting policy *(Note 2)*	**(83,131)**	(117,545)
Retained earnings, beginning of year as restated	**517,185**	134,555
Retained earnings, end of year	**948,439**	517,185

Earnings per share *(Note 9)*		
Basic	**0.042**	0.046
Diluted	**0.041**	0.045

STATEMENTS OF CASH FLOWS

For the years ended December 31	2004	2003 (restated)
Cash provided by (used for) the following activities		
OPERATING		
Net earnings	**431,254**	382,630
Add items not involving a current cash outlay		
Depletion and depreciation	**883,118**	679,004
Accretion	**44,366**	38,762
Stock-based compensation *(Note 8)*	**51,598**	5,600
Future income taxes *(Note 5)*	**203,137**	72,950
	1,613,473	1,178,946
Changes in non-cash working capital balances related to operating *(Note 14)*	**(985,697)**	791,514
	627,776	1,970,460
FINANCING		
Share issuance costs	**(137,066)**	–
Bank loan advances (repayments)	**900,000**	(145,000)
Issuance of shares	**1,990,485**	35,300
	2,753,419	(109,700)
INVESTING		
Changes in non-cash working capital balances related to investing *(Note 14)*	**109,214**	277,291
Purchase of property and equipment	**(4,030,694)**	(2,092,799)
Proceeds on disposal of property and equipment	**557,684**	41,017
Asset retirement obligations settled	**(29,974)**	(76,127)
	(3,393,770)	(1,850,618)
(Decrease) increase in cash	**(12,575)**	10,142
Cash, beginning of year	**15,968**	5,826
Cash, end of year	**3,393**	15,968

For the year ended December 31, 2004

1. SIGNIFICANT ACCOUNTING POLICIES

Chirripo Resources Inc. ("the Company") is incorporated under the laws of Alberta and its principal activity is the exploration for and development of oil and gas properties in Western Canada.

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles. In preparing these financial statements, management is required to make estimates and assumptions. In management's opinion, the financial statements have been properly prepared using careful judgement within reasonable limits of materiality and within the framework of the accounting policies summarized below:

PROPERTY AND EQUIPMENT

The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs associated with the exploration for, and the development of, petroleum and natural gas reserves, whether productive or unproductive, are capitalized in cost centres. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties and drilling and overhead expenses related to exploration and development activities and the estimated net present value of related future asset retirement obligations. Proceeds from the disposal of oil and gas properties and production equipment are applied as a reduction of the cost of the remaining assets, except when such a disposal would change the depletion and depreciation rate by more than 20 percent, in which case a gain or loss on disposal would be recorded.

Property and equipment is characterized as long-lived assets held for use and as such, are tested quarterly for impairment to ensure that the carrying amount of the property and equipment is recoverable and does not exceed the non-discounted cash flows expected from the production of proved reserves, undeveloped land and future development projects.

If the carrying value is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the property and equipment exceeds the sum of the discounted cash flows from proved plus probable reserves, undeveloped land and future development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. Any permanent impairment is included in earnings for the period.

DEPLETION AND DEPRECIATION

Costs related to oil and gas properties are depleted on a unit-of-production method based on the Company's gross share of total proved oil and gas reserves before royalties as determined by independent reserve engineers. Costs eligible for depletion include total capitalized costs, less the cost of unproved properties, plus estimated future development costs of proved undeveloped reserves. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion until it is determined whether proved reserves have been established or impairment occurs. For purposes of the depletion calculation, proved oil and gas reserves are converted to a common unit of measure on the basis of the relative energy content of 6,000 cubic feet of natural gas per barrel of oil.

Property and equipment, other than petroleum and natural gas properties, are stated at cost, less amortization, calculated on a straight-line basis at the following annual rates:

Furniture and fixtures	20%
Computer equipment	30%

Joint-venture activities

Substantially all of the Company's petroleum and natural gas exploration and production activities are conducted jointly with others, and, accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

Bank loans

The Company classifies borrowings as a current liability where the lender has a right to demand payment within twelve months, or where the lender may decide not to roll over the borrowing for a further lending period longer than twelve months.

Asset retirement obligations

An asset retirement obligation is recognized at its fair market value in the period in which it is incurred and a corresponding increase in the carrying value of property and equipment. The fair value calculation is based on discounted cash flows using industry guidelines and management's estimate on a property by property basis. The liability is subsequently adjusted due to the passage of time and is recognized as an accretion expense in the statement of operations and retained earnings. The liability is further adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. The increase in the carrying value of property and equipment is amortized using the unit-of-production method based on estimated gross proved reserves as determined by independent reserve engineers. Actual costs, as incurred, are charged to the asset retirement obligation.

Revenue recognition

Revenues from the sale of oil and natural gas sales are recorded in earnings when title passes to a third party.

Income taxes

The Company utilizes the asset and liability method of accounting for income taxes. Under this method, future income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax basis, using tax rates that are expected to be in effect when the related income and expense items are expected to be realized. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. In addition, the future benefits of income tax assets, including unused tax losses, are recognized subject to a valuation allowance, to the extent that it is more likely than not that such future benefits will ultimately be realized.

Flow-through shares

Income tax legislation permits the flow through to shareholders of income tax deductions relating to certain qualified resource expenditures. The income tax benefits renounced are reflected as a future income tax liability and deducted from share capital when the expenditures are renounced.

Per share amounts

Basic earnings per share are calculated using the weighted average number of shares outstanding during the year. Diluted earnings per share are calculated based on the treasury stock method which assumes that any proceeds obtained on the exercise of options and warrants would be used to repurchase common shares at the average price during the period.

STOCK-BASED COMPENSATION

The Company has one stock-based compensation plan described in Note 8. The fair value for each stock option granted is estimated on the date of the grant using the Black-Scholes option pricing model. These fair value costs are recognized in current earnings with a corresponding increase to contributed surplus over the vesting period of the grant. As the options are exercised, the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

MEASUREMENT UNCERTAINTY

The preparation of financial statements, in conformity with Canadian generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accounts receivable are stated after evaluation as to their collectibility and an appropriate allowance for doubtful accounts is provided where considered necessary. The amounts recorded for depletion of property and equipment and the provision for asset retirement obligations are based on estimates. The asset impairment test is based on such factors as estimated proved reserves, production rates, oil and natural gas prices, future development costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods could be material if actual results differ from these estimates.

2. CHANGES IN ACCOUNTING POLICIES

IMPAIRMENT OF LONG-LIVED ASSETS

In January 1, 2004, the Company adopted AcG-16 "Oil and Gas Accounting – Full Cost". The new guideline issued by the CICA replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how impairment is tested and is consistent with CICA section 3063 "Impairment of Long-lived Assets". Under AcG-16, impairment is recognized if the carrying amount of the property and equipment exceeds the sum of the undiscounted cash flows expected to result from the Company's proved reserves. Pursuant to this guideline, the change was applied prospectively and prior periods have not been restated. The adoption of the new guideline had no effect on the financial statements.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for asset retirement obligations. These recommendations replaced the former policy on future site restoration, and as a result, have been treated as a change in accounting policy. Pursuant to these recommendations, the change was applied retroactively and prior periods have been restated.

Previously, the Company recorded a provision for future site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis. Under the new recommendations, an asset retirement obligation is recognized at fair value when incurred and a corresponding asset retirement cost is capitalized to property and equipment and amortized to income over its estimated useful life.

3. PROPERTY AND EQUIPMENT

2004

	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	9,184,500	2,259,399	6,925,101
Furniture and fixtures	14,367	13,298	1,069
Computer equipment	27,443	18,200	9,243
Asset retirement cost	476,620	203,136	273,484
	9,702,930	2,494,033	7,208,897

2003

	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	5,712,331	1,424,244	4,288,087
Furniture and fixtures	13,752	10,546	3,206
Computer equipment	25,589	12,587	13,002
Asset retirement cost	444,124	163,536	280,588
	6,195,796	1,610,913	4,584,883

During the current twelve-month period, the Company capitalized $96,566 (2003 – $70,675) of general and administrative expenses related to exploration activities. Included in accounts payable and accruals is $110,841 (2003 – $277,291) of property and equipment purchases.

The future commodity prices used in the impairment test were based on December 31, 2004 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The table summarizing the future benchmark prices the Company used in the impairment test can be found on page 8.

4. BANK LOANS

The bank loan is a revolving, non-reducing operating demand loan with a maximum amount available of $2,400,000 (2003 – $1,800,000) which revolves by increments of $25,000. Amounts drawn under the facility bear interest at the bank's prime rate plus 1 percent and there is a standby fee of 1/8 of one percent on undrawn amounts. As at December 31, 2004, the amount drawn on the operating demand loan is $1,875,000 (2003 – $975,000).

The Company's lending facility also includes a non-revolving acquisition demand loan with a maximum available of $1,500,000. Amounts drawn under the facility bear interest at the bank's prime rate plus 1 1/4 percent and there is a standby fee of 1/8 of one percent on undrawn amounts. On May 13, 2004, the Company's acquisition demand loan was amended to include a development facility of up to $600,000 to equip and tie-in production.

The loans are secured by a demand promissory note, a general assignment of book debts and a floating debenture in the amount of $5,000,000. The bank loan is subject to certain affirmative financial covenants. As at December 31, 2004 the Company is in compliance with all such covenants.

5. INCOME TAXES

At December 31, 2004, the Company has approximately $4,683,000 (2003 – $2,772,000) of tax pools and $109,654 (2003 – nil) of unclaimed share issuance costs available to reduce future taxable income. The benefit of these tax pools has been recognized in these financial statements.

The income tax expense differs from the amount that would be expected by applying the current tax rates for the following reasons:

	2004	2003
Earnings before taxes	**634,391**	551,580
Expected tax expense at 38.95% (2003 – 40.79%)	**247,095**	211,003
Tax effect of expenses not deductible for tax purposes:		
Stock-based compensation	**20,613**	2,284
Crown royalties	**179,503**	197,310
Tax effect of amounts deductible for tax purposes:		
Resource allowance	**(138,444)**	(15,536)
Alberta Royalty Tax Credit	**(25,328)**	(35,898)
Other	**(21,906)**	126
Impact of lower future tax rates	**(58,396)**	(55,339)
Provision for income taxes	**203,137**	168,950
Allocated to:		
Current	–	96,000
Future	**203,137**	72,950

The components of the net future income taxes liability are as follows:

	2004	2003
Future income tax liabilities		
Petroleum and natural gas properties	**858,605**	569,122
Future income tax assets		
Asset retirement obligations	**(76,993)**	(31,978)
Share issue costs	**(40,243)**	–
Non-capital loss carryforward	**(51,585)**	–
Other	–	(194)
Net future income tax liability	**689,784**	536,950

6. ASSET RETIREMENT OBLIGATIONS

Future asset retirement obligations were estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in the future periods. The Company estimates the undiscounted cash flows related to asset retirement obligations, adjusted for inflation, to be incurred over the estimated reserve life of the underlying long-lived assets will total $911,550. The fair value of the asset retirement obligation as at December 31, 2004 is $495,835 using a discount rate of nine percent and an inflation rate of two percent. These payments are expected to be made over the life of the wells with the majority of the costs incurred between 2010 and 2015.

The change in accounting for asset retirement obligations, as compared to the site restoration approach, increased the Company's capital assets as at December 31, 2003 by $280,588, decreased the Company's retained earnings as at December 31, 2003 by $83,131 and increased the Company's abandonment liability as at December 31, 2003 by $363,719.

	2004	2003
Balance, at December 31, 2003	**448,948**	430,692
Increase in obligations	**32,495**	55,621
Obligations settled	**(29,974)**	(76,127)
Accretion expense	**44,366**	38,762
Balance, at December 31, 2004	**495,835**	448,948

7. SHARE CAPITAL

AUTHORIZED

An unlimited number of common voting shares
An unlimited number of preferred shares

The preferred shares may be issued from time to time in one or more series, each series consisting of a number of preferred shares as determined by the Board of Directors of the Company which may also fix the designations, rights, privileges, restrictions and conditions attaching to each series of preferred shares. There are no preferred shares issued.

ISSUED

COMMON SHARES	NUMBER OF SHARES	AMOUNT
Balance at December 31, 2002	8,251,668	1,044,740
Issued on exercise of options	210,000	35,300
Balance at December 31, 2003	8,461,668	1,080,040
Issued on exercise of options	45,000	13,500
Issued on private placement (a)	1,500,000	1,050,000
Share issue costs net of future tax recovery	–	(66,607)
Issued on exercise of warrants (b)	534,100	453,985
Issued on exercise of agent's options (c)	150,000	105,000
Issued on private placement (d)	368,000	368,000
Share issue costs net of future tax recovery	–	(20,156)
Balance at December 31, 2004	11,058,768	2,983,762

a) On January 29, 2004 the Company closed a private placement of 1,500,000 units at a price of $0.70 per unit for total gross proceeds of $1,050,000. Each unit consisted of one common share and one-half warrant. Each full warrant entitled the holder to acquire one common share at an exercise price of $0.85 until December 15, 2004. The agent received options entitling it to acquire 150,000 units at the issue price for a period of twelve months from the closing of the offering.

b) Each of the 750,000 warrants referred to in (a) entitled the holder to acquire one common share at an exercise price of $0.85 until December 15, 2004. 215,900 warrants expired without being exercised.

c) All of the agent's options referred to in (a) were exercised in 2004. 75,000 warrants remain outstanding at December 31, 2004 with each warrant entitling the agent to acquire one common share at an exercise price of $0.85 until January 29, 2005. All of the warrants were exercised prior to January 29, 2005.

d) On June 10, 2004 the Company closed a private placement of 368,000 common shares at a price of $1.00 per common share for total gross proceeds of $368,000.

STOCK OPTIONS

The Company has established a stock option plan whereby the Company may grant options to its directors, officers and employees for up to 10 percent of the issued and outstanding common shares of the Company. Options granted prior to December 31, 2002 vest and are exercisable immediately following the grant of the options and expire five years after the date of grant. Options granted after December 31, 2002, vest evenly over a three-year period commencing one year from the date of grant and expire five years after the date of grant.

Stock option transactions were as follows:

	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Balance at December 31, 2002	517,500	0.21
Options granted	443,000	0.63
Options exercised	(210,000)	0.17
Balance at December 31, 2003	750,500	0.47
Options granted	320,000	0.90
Options exercised	(45,000)	0.30
Balance at December 31, 2004 – outstanding	1,025,500	0.61
Balance at December 31, 2004 – exercisable	410,167	0.37

At December 31, 2004, the following stock options were outstanding:

DATE OF EXPIRY	NUMBER OF STOCK OPTIONS	EXERCISE PRICE
January 14, 2005	65,000	$0.11
July 3, 2006	125,000	$0.25
September 3, 2007	72,500	$0.30
November 14, 2008	443,000	$0.63
December 1, 2009	320,000	$0.90
	1,025,500	

WARRANTS

As referred to in (c) on page 33, as at December 31, 2004, the Company had 75,000 share purchase warrants outstanding. Each warrant entitles the agent to acquire one common share at an exercise price of $0.85 until January 29, 2005.

8. STOCK-BASED COMPENSATION

The Company accounts for stock options granted to directors, officers and employees using the "fair value method", whereby compensation is recorded equal to the fair value of the option granted over the term of vesting. Since January 1, 2003, 763,000 options with an estimated fair value of $271,100 were granted and will be amortized over the three-year vesting period. Stock-based compensation expense recognized during the year was $51,598 (2003 – $5,600), leaving an unamortized balance of $213,902 (2003 – $139,500). The fair value of options granted since January 1, 2003 was estimated at the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2004	2003
Risk-free interest rate (%)	**4.5%**	3.2%
Expected volatility (%)	**40.0%**	70.0%
Expected life (years)	**5**	4
Expected dividend yield (%)	–	–

Option pricing models require the input of highly subjective assumptions including the expected price volatility. Changes in the subjective input assumptions can materially affect the fair value estimate, and therefore, the existing models do not necessarily provide a reliable measure of the fair value of the Company's stock options.

9. PER SHARE AMOUNTS

The weighted average number of common shares outstanding during fiscal 2004 was 10,207,133 (2003 – 8,357,723) shares. The number of shares added to the weighted average number of common shares outstanding for the dilutive effect of options and warrants utilizing the treasury stock method was 349,424 (2003 – 165,577).

10. COMMITMENTS

The Company has entered into an office rental lease expiring January 2007. The Company has the following minimum annual lease payments:

2005	68,190
2006	68,190
2007	5,682

11. RELATED PARTY TRANSACTIONS

During the year, the Company paid $24,707 (2003 – $57,500) for consulting services to a director of the Company, which is included in capitalized general and administrative expenses. These transactions were in the normal course of business and have been measured at the exchange amount which is the amount established and agreed upon by the related parties.

12. SEGMENTED INFORMATION

The Company operates primarily in the oil and gas industry in Western Canada and as such, is defined as having only one industry and geographic segment.

13. FINANCIAL INSTRUMENTS

The Company, as part of its operations, carries a number of financial instruments. It is management's opinion that the Company is not exposed to significant interest-rate risk (except on its bank loans), or currency risk arising from these financial instruments.

FAIR VALUE

At December 31, 2004, the estimated fair market value of cash, accounts receivable, accounts payable and accruals are equal to the book value due to the short-term nature of these accounts. The fair market value of the bank loans approximates their book value as the loans carry a floating rate of interest.

CREDIT RISK

Virtually all of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

14. Supplemental cash flow information

	2004	2003
Interest paid	**78,993**	67,847
Income tax paid	**91,076**	–

	2004	2003
Changes in non-cash working capital balances		
Accounts receivable	**(456,730)**	32,895
Prepaid expenses and deposits	**(7,376)**	232,218
Accounts payable and accruals	**(265,930)**	714,275
Net taxes payable	**(146,447)**	89,417
	(876,483)	1,068,805
Allocated to:		
Operating activities	**(985,697)**	791,514
Investing activities	**109,214**	277,291
	(876,483)	1,068,805

15. Comparative Figures

Certain of the prior year's figures have been reclassified to conform to the current year's presentation.

Directors

Michael A. Williams [1][2]
Chairman of the Board
Calgary, AB

William R. Miller [2]
Calgary, AB

Larry Braun [1][3]
Calgary, AB

Robert Vanderham [3]
Victoria, BC

John Newman [2][3]
Calgary, AB

Issa Abu-Zahra [1]
Calgary, AB

[1] *Compensation Committee Member*
[2] *Audit Committee Member*
[3] *Reserves Committee Member*

Officers

Issa Abu-Zahra
President and Chief Executive Officer
Calgary, AB

Thomas R. Wilcock
Vice-President Exploration
Calgary, AB

David A. Dakers
Secretary and Chief Financial Officer
Calgary, AB

Auditors

Meyers Norris Penny, LLP
Calgary, AB

Reserves Engineers

Paddock Lindstrom & Associates Ltd.
Calgary, AB

Legal Counsel

Gowling Lafleur Henderson LLP
Calgary, AB

Transfer Agent and Registrar

Computershare Trust Company of Canada
Calgary, AB

Bankers

National Bank of Canada
Calgary, AB

Stock Exchange

TSX Venture Exchange
Trading Symbol: CHO

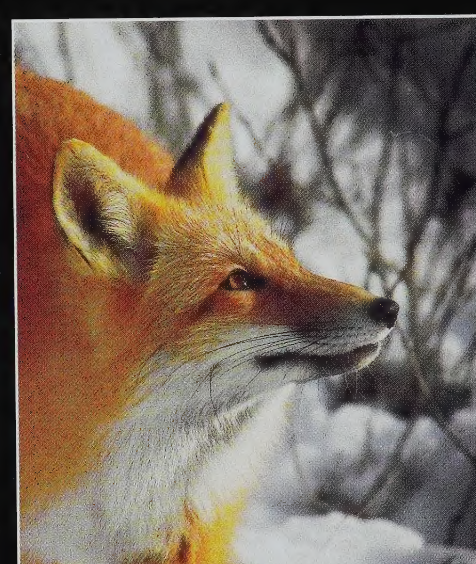
Head Office

1440 530-8th Avenue S.W.
Calgary, AB T2P 3S8
Tel: (403) 261-5858
Fax: (403) 261-5849

Abbreviations

bbls	barrels
mbbls	thousand barrels
bbls/d	barrels per day
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
mcf/d	thousand cubic feet per day
NGL	natural gas liquids
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent

Designed and Produced by Merlin Edge Inc.
Printed in Canada



keeping an eye on opportunity

CHIRRIPO RESOURCES INC.

1440 530-8TH AVENUE S.W., CALGARY, AB, CANADA T2P 3S8

TEL: (403) 261-5858   FAX: (403) 261-5849